AGING NATURAL GAS POWER PLANTS IN CALIFORNIA

STAFF PAPER

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A summary of capacity, usage, and emission characteristics of older natural gas power plants in California

Summary

As previously reported, the Energy Commission staff has examined the adequacy of the state's electrical system reserve capacity for the summer of 2003 and determined that adequate capacity is expected be available to meet the summer peak demand. However, the age of the power plants in California has raised concerns that a significant number of older facilities may lack the reliability to be available when needed. In this report, the Energy Commission staff presents information on key characteristics of the state's natural gas power plants, including unit specific information on the 25 largest natural gas facilities in state. While some forced outages will occur among these units this summer, such outages have been incorporated into the Energy Commission staff's forecasts. The Energy Commission staff continues to believe that the state will have adequate reserves this summer despite the age distribution of its generation fleet, and that its forecasts appropriately incorporate consideration of the reliability of the generation facilities in the state.

Role of Natural Gas Power Plants in California's Electric System

The Energy Commission staff estimates that more than 60,000 MW of dependable capacity (including imports) will be on-line this summer, with almost 60,000 MW of that capacity expected to be available to meet peak demand at any time. Approximately 30,000 MW of the dependable capacity is provided by in-state natural gas power plants with a capacity of 50 MW or greater. These facilities play two key roles in the operation of the state's electric system: providing needed capacity to meet peak demand, and providing important swing capacity to meet annual electricity needs when imports or hydroelectric resources are low.

The full available capacity of the system needs to be called upon only to meet peak demand, which in California typically falls on hot summer afternoons. During those relatively few hours of the year, virtually all existing power plants are relied on to provide generating capacity or other reliability services. Given that natural gas units provide half of the available capacity, their availability at times of peak demand is an important aspect of system reliability. An overview of the age, emissions and efficiency characteristics, and recent operations of these natural gas power plants is presented below. While these characteristics are not direct measures of reliability, they do show that most of this capacity is from reasonably efficient units, and most of the older units have had recent investment from their owners in modern pollution control equipment.

The extent to which these facilities will be used to meet annual demand in California is governed by the hour-to-hour dispatch of generating resources by the operators of the different control areas over the course of the year. Power plants in California are dispatched to meet the demand for electricity in a ‘merit order’. The merit order reflects each unit’s relative variable costs of production, with hydro generation, as a rule, being least expensive, followed by nuclear and coal, then natural gas. Renewable resources and cogeneration are generally dispatched based on contractual or physical constraints. When available, these resources tend to be dispatched before most natural gas units. Natural gas-fired resources are generally dispatched according to their heat rates. Units with higher heat rates have higher positions in the merit order and are used less frequently. Other factors, such as transmission losses and costs are also factored into the merit order.

The system of constrained merit order dispatch is intended to ensure that electric supply and demand remain balanced throughout the year, including on days of peak demand, while attempting to minimize the overall costs of operating the system. The year-to-year variation in the availability of hydro resources due to changes in precipitation in California and the Pacific Northwest greatly influences the mix of resources called upon to meet California’s demand during the year. The Western power system has been designed to accommodate variable hydro resources. When precipitation runoff is bountiful, hydroelectric generation is used and other generating plants, mostly gas-fired, are idled. When hydroelectric energy generation is low, a combination of increased imports, if they are available, and increased generation by in-state natural gas power plants will make up the difference. Differences in capacity factors between 2001 (low hydro and imports) and 2002 (relatively normal hydro and imports) for the 25 largest units (shown in **Table 1**, included at the end of the report) reflect this ‘swing’ role of the natural gas-fired capacity within the system.

The natural gas-fired facilities discussed below remain an important part of the overall system, providing both needed capacity for meeting peak demand and intermediate capacity to help meet annual energy requirements during low hydro years.

Natural Gas Power Plant Characteristics

Energy Commission staff has prepared the following overview of the age, emissions and efficiency characteristics, and recent operations of these natural gas power plants. While not direct measures of the reliability of these facilities, the fact that the vast majority of this capacity is from units that are relatively efficient provides an incentive for owners to keep the units available. The fact that the owners of a majority of this capacity have either built the facilities in recent years or invested in retrofitting with selective catalytic reduction (SCR) emission control equipment also suggests that owners are acting to keep the units available. While the Energy Commission staff recognizes that some forced outages will occur among these units this summer, such outages have been incorporated into the Energy Commission staff’s forecasts. The Energy Commission staff continues to believe that the state will have adequate reserves this summer despite the age distribution of its generation fleet.

Table 1 provides unit-specific information for the 25 largest natural gas power plants in the state. This information includes the name, owner, and location of each facility, and the dependable capacity, the start-up or re-power date, the capacity factor (percent of time the unit operated during the year), efficiency (heat rate), and permitted emissions level of each set of units within those facilities. These 25 facilities, roughly those over 500 MW, represent approximately 80 percent of the in-state natural gas-fired capacity. The table has been color coded to distinguish among different categories of units, as summarized in **Table 2**. Of the 1,831 MW from older units without SCR that are not currently expected to shutdown, 1,036 MW are from Contra Costa unit 6 and Pittsburg unit 7. These units face deadlines to install SCR or shutdown by late 2004 and early 2005, respectively. The other units in this category do not face current regulatory deadlines to retrofit or stop operation.

Table 2. Summary of categories of the 25 largest natural gas power plants in California

Category	MW	Table 1 Shading
New unit with SCR	6,784	No shading
Older unit retrofit with SCR	12,783	Yellow
Older unit, no SCR, shutdown not planned	1,831	Purple
Older unit, no SCR, shutdown expected	2,412	Blue
Total	**23,810**	

Figure 1 shows the age breakdown of the capacity from existing natural gas-fired facilities over 50 MW. While almost half of this capacity dates from the 1950s or 1960s, the data do not suggest that these older power plants are all dirty or inefficient. Though the overall age of these facilities raises a degree of concern, consideration of the efficiency and emissions profiles of these units suggests that the vast majority of this capacity is from units that have installed current emission control equipment and are reasonably efficient. In addition, more than 25 percent of the state's natural gas-fired-capacity either was built or repowered since 2000.

Figure 1. Age of Natural Gas Power Plant Capacity in California

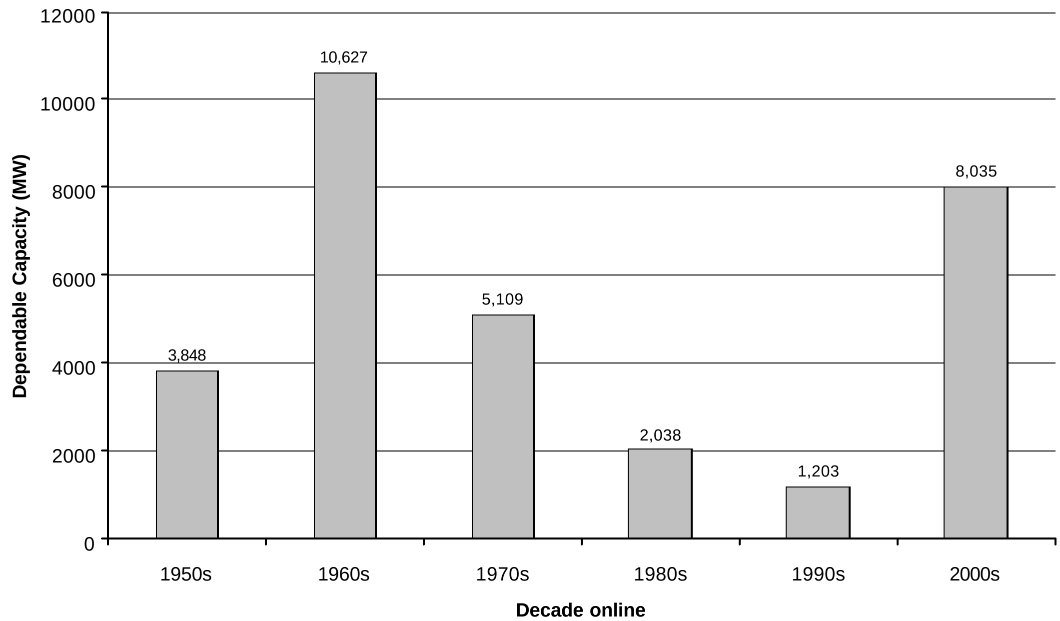


Table 3 shows the MW capacity of units in different emission categories based on NOx permit emission limits. **Figure 2** shows the emission characteristics for the capacity brought online in each decade. Almost one-third of the natural gas-fired capacity in California has a permit limit of 5 ppm NOx or less, and more than 75 percent are limited to 15 ppm or less. These facilities are in three categories. Combined-cycle and cogeneration facilities that have come on-line since the mid-1990s have permit limits below 5 ppm. Simple-cycle units ('peakers') that have come on-line in recent years are typically permitted at 5 ppm. Most of the steam boiler units built in the 1950s and 1960s have been retrofit with SCR and now have permit limits between 5 and 15 ppm. While these facilities could not control NOx emissions to that degree when they were initially constructed, most have opted to retrofit. Facilities with limits above 15 ppm are either steam boilers that have not been retrofit with SCR, or older simple-cycle units.

Table 3. Dependable Capacity by permitted NOx emission levels (all natural gas power plants 50 MW and larger)

NOx permit limit (ppm)	Capacity		Cumulative Capacity	
	MW	%	MW	%
<= 5	9,793	31.7	9,793	31.7
5.1 to 15	13,864	44.9	23,657	76.7
15.1 to 50	3,591	11.6	27,248	88.3
50.1 to 100	2,284	7.4	29,532	95.7
> 100	1,248	4.0	30,780	99.7
NA	80	0.3	30,860	100.0

The NOx permit limit was not readily available for one 80 MW unit.

Figure 2. Dependable capacity by decade online and NOx emission permit levels

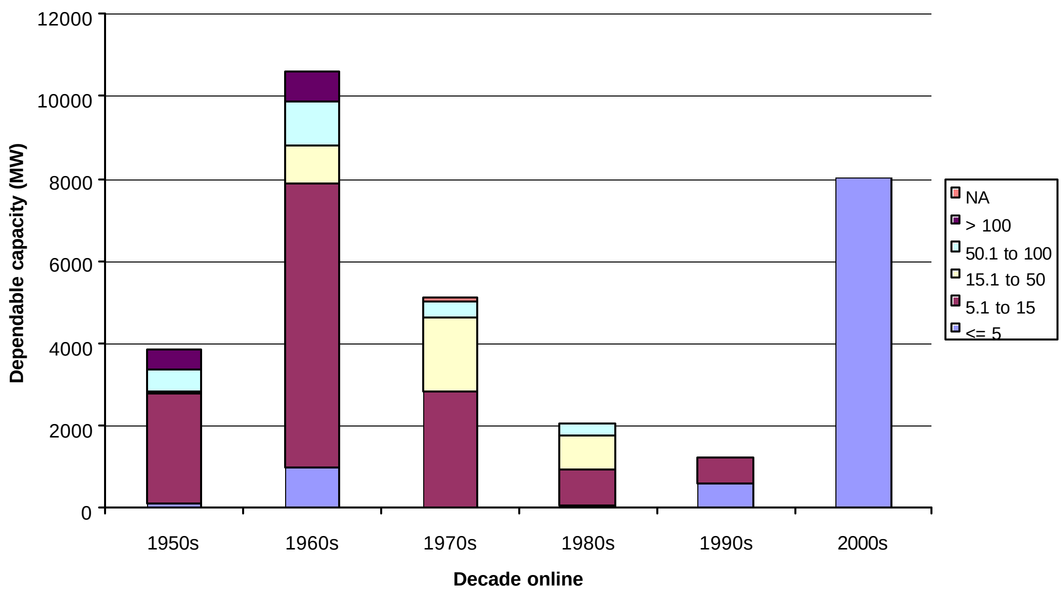
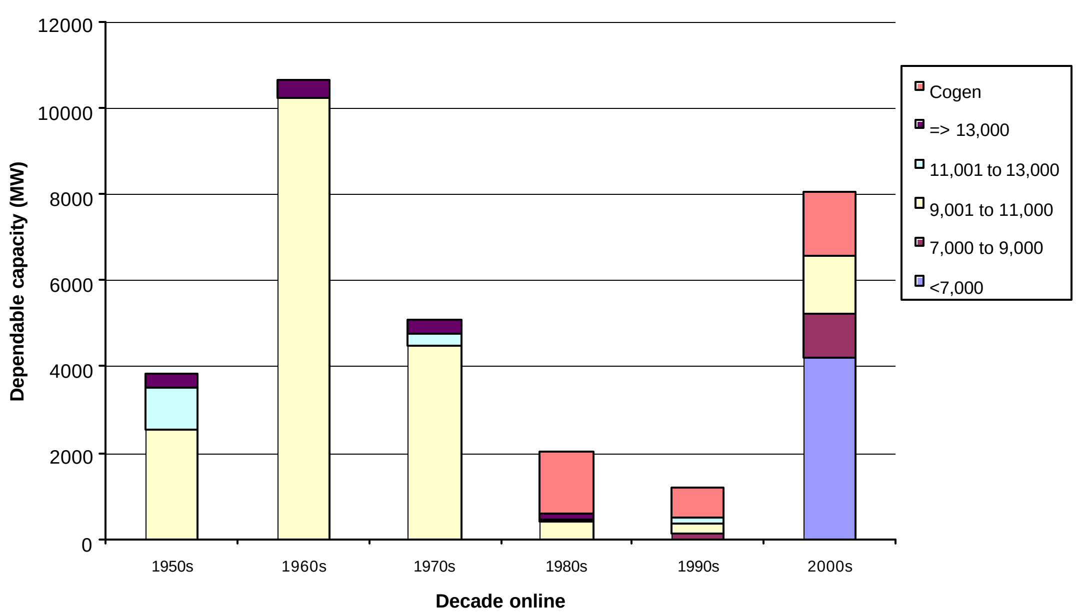


Table 4 shows the MW capacity of natural gas-fired units in different efficiency categories based on approximate heat rates. This table shows that the majority of capacity from these units generates electricity within a narrow heat rate range. This range, 9,000 to 11,000 Btu/kWh, is the general range in which relatively efficient older steam boilers and modern peaking combustion turbines both operate. **Figure 3** shows that the vast majority of capacity remaining online from the 1950s through 1970s operates in this range. Units that have come online this decade (or are expected to by August 2003) include more than 4,000 MW from modern combined cycle power plants that are significantly more efficient. Cogeneration units are presented separately, without an estimate of their heat rate. These units, in addition to generating electricity, also supply heat to host industrial facilities. This complicates the use of heat rate as a measure of efficiency. In addition, such facilities are often primarily designed to supply industrial heat to the host facility, with the generation of electricity to the grid a side-benefit.

Table 4. Dependable Capacity by approximate heat rate (all natural gas power plants 50 MW and larger)

Approximate heat rate (Btu/kWh)	Capacity		Cumulative Capacity	
	MW	%	MW	%
<7,000	4,186	13.6	4,186	13.6
7,000 to 9,000	1,135	3.7	5,321	17.2
9,001 to 11,000	19,259	62.4	24,580	79.7
11,001 to 13,000	1,453	4.7	26,033	84.4
=> 13,000	1,201	3.9	27,234	88.3
Cogeneration units	3,626	11.7	30,860	100.0

Figure 3. Dependable capacity by decade online and approximate heat rate (Btu/kWh)



Factors Affecting Power Plant Retirement Decisions

The information presented here cannot be used by itself to accurately predict future unit availability or retirements. Additional analysis and knowledge of power plant performance and usage characteristics would be needed to better evaluate the risk that capacity from older units would be unavailable in the future. Currently, with the information available to the state, it is not possible to predict with confidence how long units will remain sufficiently profitable to induce their owners to maintain their availability.

Power plants are operated to the economic advantage of their owners, whether the owners are independent power producers, investor-owned utilities or publicly owned utilities. However, power plant operations are constrained by utility practice and regulations that ensure the reliability of the electric system and avoid unacceptable economic, public health, and environmental impacts.

As noted in the tables and figures, some of these power plants are decades old, which can increase the cost of maintenance or make them unreliable. Whether these power plant units remain available to provide capacity and reliability services is an economic decision of the owner. This decision is usually determined by the expected net profitability of a unit (*i.e.* the difference between expected revenues and expected operation costs, which include fuel, maintenance, and any necessary capital costs). A number of units have been retired in recent years or are slated for retirement in the near term. These retirements have, for the most part, been associated with decisions by the facility owner to replace older, less efficient units that would have required emission control upgrades with new, more efficient and cleaner burning units.

Power plant owners will make investments to maintain a unit's availability as long as it is profitable to do so. Revenue guarantees, such as income from the California Department of Water Resources' long-term power purchase contracts or income from the California Independent System Operator's Reliability-Must-Run contracts, tend to encourage such investments, as do expectations of high electricity spot market prices. Expectations of low maintenance, fuel and going-forward capital costs also encourage owners to keep units available.

Conversely, the owner of a power plant unit may decline to invest in the maintenance necessary to maintain a unit's availability if faced with low or uncertain revenue expectations or high or uncertain cost expectations. If a plant is not efficient and does not have revenue guarantees for its output, it may not be dispatched often enough to recover its costs. If a plant requires extensive maintenance or capital costs to maintain its availability (*e.g.* boiler tube replacement, or SCR retrofit to control NOx emissions), higher revenues would be needed to maintain profitability.

The information most directly related to the owner's decision (*i.e.* expected revenues, costs, and profit expectations) is confidential, proprietary, or unknown. Indirect indicators of profitability such as historic annual capacity factor, annual energy generation, forced outage rates, and permitted NOx emissions rates could be examined and analyzed to provide more insight as to the potential for specific unit retirements. In addition, identifying which units have guaranteed revenue streams, Reliability-Must-Run contracts, or anticipated costly capital requirements, could help identify units less likely or more likely to retire. However, these analyses would still not be conclusive. As such, we have not attempted to make this kind of analysis in this report. The Energy Commission's near-term Electricity Supply/Demand Balance Assessments are an attempt to consider many of these factors, but a degree of uncertainty remains.

Conclusions

Energy Commission staff has provided an overview of the age, emissions and efficiency characteristics, and recent operations of the natural gas power plants in California. While this information cannot be used to predict future availability or retirement of specific units, most of the natural gas-fired capacity is from units that are relatively efficient, providing an incentive for owners to keep the units available. In addition, the owners of a majority of this capacity have either built the facilities in recent years or invested in retrofitting steam boiler units with current emission control technology, suggesting that owners are acting to keep the units available. While some forced outages will occur among these units this summer, such outages have been incorporated into the Energy Commission staff's forecasts. The Energy Commission staff continues to believe that the state will have adequate reserves this summer despite the age distribution of its generation fleet, and that its forecasts appropriately incorporate consideration of the reliability of the generation facilities in the state.

Table 1: Characteristics of the Twenty-five Largest Natural Gas Power Plants in California

Plant Name (Owner) Unit	County	Facility Dependable Capacity	Unit Dependable Capacity	Year Online/ Repowered	Capacity Factor (percent) 2001	2002	App. Heat Rate (Btu/Kwh)	NOx Permit Limit (ppm)	Comments
Moss Landing Power Plant (Duke Energy)	**Monterey**	**2,545**							
Steam units 6 & 7			1,485	1968	65	30	9,000	10	
Combined cycle units 1 & 2			1,060	2002	New units		7,000	2.5	
Alamitos (AES Corp)	**Los Angeles**	**2,087**							
Steam units 1 & 2			348	1956, 1957	13	10	13,000	9	
Steam units 3 & 4			642	1961, 1962	46	30	11,000	9	2003 RMR contract for Unit 3 only
Steam units 5 & 6			963	1964, 1966	58	26	10,000	9	
Peaker unit 7			134	1969	3	0.5	14,000	90	Shutdown expected 12/31/03
Haynes (LADWP)	**Los Angeles**	**1,570**							
Steam units 1 & 2			444	1959, 1962	33	27	10,000	9	
Steam units 3 & 4			444	1964, 1965	17	9	10,000	36	Shutdown of Unit 3 expected in 9/04 and of Unit 4 in 11/03
Steam units 5 & 6			682	1967	25	18	10,000	9	
Ormond Beach (Reliant Energy)	**Ventura**	**1,492**							
Steam units 1 & 2			1492	1971, 1973	42	18	10,000	9	
Pittsburg Power Plant (Mirant)	**Contra Costa**	**1,332**							
Steam units 5 & 6			632	1960, 1961	60	22	10,000	12	2003 RMR contract
Steam unit 7			700	1972	56	42	10,000	48	2003 RMR contract; retrofit with SCR expected by early 2005
Redondo Beach (AES Corp)	**Los Angeles**	**1,317**							
Steam units 5 & 6			350	1954, 1957	17	4	13,000	7	
Steam units 7 & 8			967	1967	44	23	10,000	5	
Morro Bay Power Plant (Duke Energy)	**San Luis Obispo**	**1,021**							
Steam units 1 & 2			342	1955, 1956	30	4	11,000	150	Proposed replacement facility in review by Energy Commission; plans to retire Units 1 to 4 after replacement project is online
Steam units 3 & 4			679	1962, 1963	55	24	10,000	56	

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Encina (Dynegy & NRG)	**San Diego**	**971**							
Steam units 1 to 3			320	1954-1958	40	18	11,000	12	2003 RMR contract
Steam units 4 & 5			635	1973, 1978	44	34	11,000	12	2003 RMR contract
Simple cycle unit			16	1968	7	1	10,000	42	dual fuel capability
La Paloma (PG&E National)	**Kern**	**968**							
units 1 to 4			968	2003	New units		6,000	2.5	
Huntington Beach (AES Corp)	**Orange**	**880**							
Steam units 1 & 2			430	1958	37	36	9,000	9	2003 RMR contract
Steam units 3 & 4			430	2002	Repowered in 2002 & 2003		9,000	5	Repowered Unit 4 expected online during 8/03
Delta LLC (Calpine)	**Contra Costa**	**861**							
Cogeneration unit			861	2002	New unit		Cogen unit	2.5	
Scattergood (LADWP)	**Los Angeles**	**803**							
Steam units 1 & 2			358	1958, 1959	28	31	10,000	7	
Steam unit 3			445	1974	25	7	10,000	7	
Etiwanda Generating Station (Reliant Energy)	**San Bernardino**	**770**							Units 1 and 2 currently unavailable due to need to install SCR
Steam units 3 & 4			640	1963	26	14	9,000	7	
Simple cycle unit 5			130	1968	7	2	15,000	74	Shutdown expected 12/31/03
High Desert (Constellation)	**San Bernardino**	**750**							
units 1 to 3			750	2003	New units		9,000	2.5	
El Segundo Power (Dynegy & NRG)	**Los Angeles**	**708**							Units 1 and 2 retired 12/31/02
Steam units 3 & 4			708	1964, 1965	37	38	10,000	9	
Contra Costa Power Plant (Mirant)	**Contra Costa**	**672**							
Steam unit 6			336	1964	63	29	10,000	175	2003 RMR contract; retrofit with SCR expected in later 2004
Steam unit 7			336	1964	52	38	10,000	15	2003 RMR contract

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Plant Name (Owner) Unit	County	Facility Dependable Capacity	Unit Dependable Capacity	Year Online/ Repowered	Capacity Factor (percent) 2001	2002	App. Heat Rate (Btu/Kwh)	NOx Permit Limit (ppm)	Comments
South Bay Power Plant (Duke Energy)	**San Diego**	**661**							
Steam units 1 & 2			297	1960, 1962	43	34	10,000	12	2003 RMR contract
steam unit 3			176	1964	33	19	10,000	12	2003 RMR contract
steam unit 4			170	1971	12	5	12,000	10	no RMR contract for 2003; Unit 4 has SCR but has been mothballed
Simple cycle unit 5			18	1966	2	0.1	10,000	39	uses jet fuel, not natural gas
Coolwater Generating Station (Reliant Energy)	**San Bernardino**	**629**							
steam unit 1			65	1961	43	14	10,000	100	
steam unit 2			82	1964	57	14	10,000	100	
Combined cycle units 3 & 4			482	1978	53	39	9,000	42	
Mandalay Generating Station (Reliant Energy)	**Ventura**	**565**							
Steam units 1 & 2			433	1959	45	26	9,000	9	
Simple cycle units			132	1970	3	0.7	19,000	25	
Valley (LADWP)	**Los Angeles**	**563**							
Steam units 1 & 2			190	1954	0	0	12,000	70	LADWP is replacing existing boilers with new combined cycle facility. Units 1 through 4 expected to shut down in 4/04. Units 1 & 2 have not operated since early 1990s
Steam units 3 & 4			323	1955, 1956	6	2	11,000	60	
Simple cycle unit 5			50	2002	13	5	10,000	5	
Sunrise Cogeneration & Power (Texaco Edison Mission) Combined cycle cogeneration Unit	**Kern**	**560**	560	2001/2003	New unit		Cogen	2	Originally approved and built as a simple-cycle unit with permitted NOx limt of 9 ppm; conversion to combined cycle expected to be online by 7/03.
Elk Hills (Sempra and Occidental) Combined cycle unit	**Kern**	**550**	497	2003	New unit		6,000	2.5	Expected online 6/03.

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Sutter (Calpine)	**Sutter**	**548**							
Combined cycle unit			548	2001	New unit		7,000	2.5	
Los Medanos (Calpine)	**Contra Costa**	**540**							
Combined cycle unit			540	2001	New unit		6,000	2.5	2003 RMR contract
Blythe I (Caithness Energy)	**Riverside**	**520**							
Combined cycle unit			520	2003	New unit		6,000	2.5	Expected to come online 6/03

Unit shut down or scheduled for shut down	Unit retrofit with SCR
No SCR installed on unit, but not currently scheduled for shutdown	New or repowered unit

Notes on data sources:

Dependable capacity figures are the Energy Commission Electricity Analysis Office's current input assumptions for modeling August, 2003, electricity supply, and includes four units (Elk Hills, Blythe 1, Huntington Beach Unit 4, and Sunrise Phase II) that were not online as of May 1, 2003, but are expected online by August. The accompanying figures also include two smaller units, Tracy Peaker and Woodland II, that are not online but are expected to be by August.

Year online/repowered represents the year the power plant was initially brought online, except for Huntington Beach, where Units 3 and 4 were substantially repowered. Unit 4 is expected to be online by August, 2003. Units that had air pollution control upgrades (*e.g.* the addition of SCR) but not a substantial repowering of the original equipment are shown with their original online date.

Capacity factors and heat rates are from the EPA Continuous Emission Monitoring System (CEMS) and Energy Information Agency Form 906 data. Heat rates provide a good measure of efficiency (the lower the value, the more efficient the unit), but vary based on operating and weather conditions. Therefore, only approximate heat rates, rounded to the nearest 1,000 Btu/KWh, are presented.

NOx permit limits are from the ARB's summary data and from local air districts. Some reported limits are estimated, with actual permits setting limits in terms of pounds per MWh rather than parts per million. Typically, NOx concentration values are normalized to 3% O2 for combustion turbines, and to 15% O2 for steam boiler units.

Independent System Operator Reliability-Must-Run contracts for 2003 are noted in the comments column.